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State of South Carolina

Before the

South Carolina Public Service Commission

In the Matter of:	)	
Application of South Carolina Electric & Gas	)	**Docket No. 2004-178-E**
Company for an Adjustment of its	)	
Rates and Charges	)	

Prepared Direct Testimony

of

Kevin W. O'Donnell, CFA

On Behalf of the

South Carolina Energy Users Committee

RETURN DATE: OK
SERVICE: OK.

October 18, 2004

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the South Carolina Energy Users Committee (SCEUC), an association of manufacturers active in many proceedings before the South Carolina Public Service Commission (the PSC or the Commission). Many of SCEUC's members take service from South Carolina Electric & Gas (SCE&G).

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I received a B.S. degree in Civil Engineering - Construction Option from North Carolina State University in May of 1982 and a Masters of Business Administration in Finance from Florida State University in August of 1984.

In September of 1984, I joined the Public Staff of the North Carolina Utilities Commission as a Public Utilities Engineer in the Natural Gas Division. In December of 1984, I transferred to the Public Staff's Economic Research Division and held the position of Public Utility Financial Analyst. In September of 1991, I joined Booth & Associates, Inc., a Raleigh, North Carolina based electrical engineering firm, as a Senior Financial Analyst. I stayed in this position until June 1994, when I accepted employment as the Director of Retail Rates for the North Carolina Electric Membership Corporation. In January 1995, I formed Nova Utility Services, Inc., an energy consulting firm. In May of 1999 I changed the name of Nova Utility Services, Inc. to Nova Energy Consultants, Inc. I am a Chartered Financial Analyst (CFA) and a member of the Association of Investment Management and Research.

I am also a senior financial analyst with MAKROD Investment Associates, which is a money management firm based in Verona, New Jersey.

I have testified before the North Carolina Utilities Commission in the following general rate case proceedings: Public Service Company of North Carolina, Inc. (Docket No. G-5, Sub 200, Sub 207, Sub 246, Sub 327, and Sub 386); Piedmont Natural Gas Company (Docket No. G-9, Sub 251 and Sub 278); General Telephone of the South (Docket No. P-19, Sub 207); North Carolina Power (Docket No. E-22, Sub 314); Piedmont Natural Gas Company (Docket No. E-7, Sub 487); Pennsylvania & Southern Gas Company (Docket No. G-3, Sub 186); and in several water company rate increase proceedings. I also submitted pre-filed testimony, and/or assisted in the settlement process, in Docket Nos. G-9, Sub 378, Sub 382, Sub 428 and Sub 461, which were general rate cases involving Piedmont Natural Gas; in Docket No. G-21, Sub 334, North Carolina Natural Gas' most recent general rate case; in Docket No. G-5, Sub 356, Public Service of North Carolina's 1995 general rate case; and in Docket No. G-39, Sub 0, Cardinal Extension Company's rate case. Furthermore, I testified in the 1995 fuel adjustment proceeding for Piedmont Natural Gas Company (Docket No. E-2, Sub 680) and submitted pre-filed testimony in Docket No. E-7, Sub 559, which was Piedmont Natural Gas Company's 1995 fuel adjustment proceeding. I also submitted pre-filed testimony and testified in Duke's 2001 fuel adjustment proceeding, which was Docket No. E-7, Sub 685.

Furthermore, I testified in Docket No. G-21, Sub 306 and 307, in which North Carolina Natural Gas Corporation petitioned the Commission to establish a natural gas expansion fund. I also submitted testimony in the Commission's 1998 study of natural gas transportation rates that was part of Docket No. G-5, Sub 386, which was the 1998 general rate case of Public Service Company of North Carolina. In September of 1999, I testified in Docket Nos. G-5, Sub 400 and G-43, which was the merger case of Public Service Company of North Carolina and SCANA Corp. I also submitted testimony and stood cross-examination in the holding company application of NUI Corp., a utility holding company located in New Jersey, which was NCUC Docket No. G-3, Sub 224, as well as NUI's merger application with Virginia Gas Company, which was Docket No. G-3, Sub 232. I also submitted pre-filed testimony and stood cross-examination in Docket No. G-3, Sub 235, which involved a tariff change request by NUI Corp. I testified in another holding company application in Docket No. E-2, Sub 753; G-21, Sub 387; and P-708, Sub 5 which was the holding company application of Piedmont Natural Gas. In June of 2001, I submitted testimony and stood cross-examination in Docket No. E-2, Sub 778, which was CP&L's application to transfer Certificates of Public Convenience and Necessity (CPCN) from two of the Company's generating units to its non-regulated sister company, Progress Energy Ventures. In November of 2001, I testified in Duke Energy's restructuring application, which was Docket No. E-7, Sub 694. In January 2002, I presented testimony in the merger application of Duke Energy Corp. and Westcoast Energy. In April of 2003, I submitted testimony in Dockets Nos. G-9, Sub 470, Sub 430, and E-2, Sub 825, which was the merger application of Piedmont Natural Gas and North Carolina Natural Gas. In May of 2003, I submitted testimony in the general rate case of Cardinal Pipeline Company, which was Docket No. G-39, Sub 4. In July, 2003, I filed testimony in Docket No. E-2, Sub 833, which is CP&L's 2003 fuel case proceeding.

In August of 2002, I submitted pre-filed testimony and stood cross-examination before the South Carolina Public Service Commission in Docket No. 2002-63-G, which was Piedmont's 2002 general rate case.

In May of 1996, I testified before the U.S. House of Representatives, Committee on Commerce and Subcommittee on Energy and Power concerning competition within the electric utility industry.

I am also very active in the wholesale power markets as my firm, Nova Energy Consultants, Inc., is the electrical consultant for several municipalities in North Carolina that purchase all of their power supplies on the open wholesale market. I have also worked with North Carolina and South Carolina municipalities in presenting comments to the Federal Energy Regulatory Commission regarding the opening of the wholesale power markets in the Carolinas.

I have also published the following articles: Municipal Aggregation: The Future is Today, *Public Utilities Fortnightly*, October 1, 1995; Small Town, Big Price Cuts, *Energy Buyers Guide*, January 1, 1997; and Worth the Wait, But Still at Risk, *Public Utilities Fortnightly*, May 1, 2000. All of these articles dealt with my firm's experience in working with small towns that purchase their power supplies in the open wholesale power markets.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is, first, to recommend a reasonable return on equity that should be allowed South Carolina Electric & Gas (SCE&G) in this case and, second, to address important rate design and tariff concerns.

Q. WHAT IS YOUR OPINION OF THE COMPANY'S REQUESTED REVENUE INCREASE IN THIS CASE?

A. My analysis of SCE&G's rate filing indicates that the Company's requested rate increase is clearly excessive and that the Company's request to include $3.5 million expense associated with amortizing GridSouth expenses should be disallowed.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS ASIDE FROM THE ABOVE REVENUE RECOMMENDATIONS FOR THE COMMISSION IN THIS CASE?

A. Yes, I do. SCE&G is herein requesting to change its credit standards so that customers with credit problems may be required to place large deposits with the utility. In my opinion, the Company has failed to provide evidence that merit such a change in credit standards for manufacturers within the state.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED RATE DESIGN CHANGES IN THIS CASE?

A. I have reviewed the cost-of-service study filed by SCE&G in this case and agree with the manner in which the study was completed. If the Commission grants SCE&G a higher rate of return than I am recommending in this case, I recommend that it then adjust customer class rates proportionately to the increase sought by the Company in this case.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

1. The return on equity that SCE&G should be granted in this case is 10.0%;
2. SCE&G's request to amortize GridSouth expenses should be disallowed;
3. SCE&G's proposal to change its credit standards is not supported by any evidence put forward by the Company and should be rejected;
4. SCE&G's proposal to use a summer coincident peak (CP) cost-of-service study for use in developing the proper rate design is appropriate for this proceeding; and
5. Instead of retracting the interruptible riders associated with Schedules 23 and 24, the Company should expand the interruptible credits.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. The remainder of my testimony is divided into nine sections as follows:

I. Economic and Legal Guidelines for Fair Rate of Return
II. Cost of Common Equity
    A. DCF Analysis
    B. Return on Equity Recommendation
III. Review of Company Witness Malkiel's Testimony
IV. Requested GridSouth Expenses
V. Requested Change in Credit Standards
VI. Interruptible Riders
VII. Cost-of-Service and Rate Design

I. ECONOMIC AND LEGAL GUIDELINES FOR FAIR RATE OF RETURN

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND LEGAL CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE FAIR RATE OF RETURN WHICH SCE&G SHOULD BE ALLOWED THE OPPORTUNITY TO EARN.

A. The theory of utility regulation assumes that public utilities are natural monopolies. Historically, it was assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. Even though deregulation for the procurement of natural gas and electric utility supplies is rapidly spreading, the delivery of these products to end-use customers will continue to be considered a natural monopoly for the foreseeable future. When it is deemed that a perceived natural monopoly does in fact exist, regulatory agencies assign exclusive franchised territories to public utilities in order for these utilities to provide services more efficiently and at the lowest possible cost. The assignment of such an exclusive territory to a utility is dependent upon the utility, in turn, providing adequate service at a fair price.

The current industry structure naturally raises the question, what constitutes a fair price? The generally accepted answer is that a prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the cost of providing utility service and earn a fair rate of return on invested capital. This fair rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Obviously, since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies and consumers. If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise new capital on reasonable terms.

Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the fair rate of return for a utility.

In the case of Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the U.S. Supreme Court recognized that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal guidance concerning the return which public utilities should be allowed to earn:

In that case, the U.S. Supreme Court specifically stated that:

> "...the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital." (320 U.S. at 603)

II. COST OF COMMON EQUITY

A. Discounted Cash Flow (DCF) Analysis

Q. CAN YOU PLEASE EXPLAIN THE DISCOUNTED CASH FLOW METHOD?

A. Yes. The DCF method is a widely used method for estimating an investor's required return on a firm's common equity. In my experience with the Public Staff of the North Carolina Utilities Commission and as a consultant in the Carolinas, I have seen the DCF method used much more often than any other method for estimating the appropriate return on common equity. Consumer advocate witnesses, utility witnesses and other intervenor witnesses have used the DCF method in their analyses. The DCF method is based on the concept that the price which the investor is willing to pay for a stock is the discounted value or present worth of what the investor expects to receive as a result of purchasing that stock. This return to the investor is in the form of future dividends and price appreciation. However, price appreciation can be ignored since appreciation in price is only realized when the investor sells the stock. Therefore, the only income that the investor will receive from the company in which it invests is the dividend stream. Mathematically, the relationship is:

Let D = dividends per share in the initial future period
g = expected growth rate in dividends
k = cost of equity capital
p = price of asset (or present value of a future stream of dividends)

$$\text{then } P = \frac{D}{1+k} + \frac{D(1+g)}{(1+k)^2} + \frac{D(1+g)^2}{(1+k)^3} + \frac{D(1+g)^{t-1}}{(1+k)^t}$$

This equation represents the amount (P) an investor will be willing to pay for a share of common equity with a given dividend stream over (t) periods.

Reducing the formula to an infinite geometric series, we have:

$$P = \frac{D}{k-g}$$

Solving for k yields:

$$k = \frac{D}{P} + g$$

Q. MR. O'DONNELL, DO INVESTORS IN UTILITY COMMON STOCKS REALLY USE THE DCF MODEL IN MAKING INVESTMENT DECISIONS?

A. Absolutely. Utility investors tend to be individuals or institutions interested in current income. The average stock investor interested in income will use the DCF to calculate how much funds he/she will receive relative to the initial investment, which is defined as the dividend yield and the amount of funds that they can expect in the future from the growth in the dividend. Both of these actions are central to the basic tenant of the DCF model that incorporates a dividend yield and a growth rate for dividends.

Q. HAVE YOU USED THE DCF MODEL IN ANALYZING COMMON STOCKS FOR INVESTMENT PURPOSES?

A. Yes. I have used the DCF method extensively in analyzing common stocks for potential personal purchases as well as for purchases contemplated for money management clients.

The DCF method is intuitively a very simple model to understand. To determine the total rate of return one expects from investing in a particular equity security, the investor adds the dividend yield which he or she expects to receive in the future to the expected growth in dividends over time.

Q. HAVE YOU APPLIED THIS METHOD TO ANY PUBLICLY TRADED COMPANIES THAT ARE SIMILAR IN NATURE TO SCE&G?

A. Yes, I developed a group of 25 comparable companies.

I developed this group of comparable companies to ensure that the return on equity for SCE&G developed in this analysis is consistent with the returns which can be obtained from similar equity investments in the open market.

Since SCE&G is not publicly traded itself, I used financial data for its parent company, SCANA Corp, to determine the rate of return specific to the utility.

Q. CAN YOU PLEASE EXPLAIN HOW YOU SELECTED THESE 25 COMPANIES FOR YOUR COMPARABLE GROUP?

A. Yes.

All of the companies in my comparable group are listed in <u>The Value Line Investment Survey</u> "Electric Utility Industry" group. The companies in my sample group are also involved in the natural gas business and are subject in varying degrees to the same federal laws, similar regulatory benefits and constraints, capital requirements, and competitive forces as SCE&G.

A further screen I used in developing my comparable group was the S&P Stock Rating to include only those companies in the comparable group which have a S&P Stock Rating, which measures stability of earnings and dividends, of A-, B+, or B. The parent company of SCE&G, SCANA Corp., has a S&P Stock Rating of B+, so I chose to include only those companies that had S&P Stock ratings of A-, B+, or B.

I also chose to exclude companies that either paid no dividend or had recently cut their dividend.

Q. WHAT DIVIDEND YIELD DO YOU THINK IS APPROPRIATE FOR USE IN THE DCF MODEL?

A. I have calculated the dividend yield by averaging the dividend yield expected over the next 12 months for each company, as reported by the Value Line Investment Survey. The period covered is from April 9, 2004, through October 1, 2004. My results appear in O'Donnell Exhibit No. 1 and show a dividend yield range of 4.2% to 4.3% for the comparable group and 4.1% to 4.2% for SCANA Corp. over the 26-week, 13-week, and 4-week time periods.

Q. PLEASE ELABORATE ON HOW YOU DEVELOPED THE DIVIDEND YIELD RANGES DISCUSSED ABOVE?

A. I developed the dividend yield range for the comparable group by averaging each Company's dividend yield over each of the three time periods analyzed. Similarly the dividend yield range of 4.1% to 4.2% for SCANA Corp. is the average dividend yield range for the Company over the 26-week, 13-week, and 4-week time periods analyzed.

Q. HOW DID YOU DERIVE THE EXPECTED GROWTH RATE?

A. I used several methods in determining the growth in dividends which investors expect. The first method I used was an analysis commonly referred to as the plowback ratio method. If a company is earning a rate of return (r) on its common equity, and it retains a percentage of these earnings (b), then each year the earnings per share (EPS) are expected to increase by the product (br) of its earnings per share in the previous year. Therefore, br is a good measure of growth in dividends per share. For example, if a company earns 15% on its equity and retains 50% (the other 50% being paid out in dividends), then the expected growth rate in earnings and dividends is 7.5% (50% of 15%). To calculate a plowback for the comparable group, I used the following formula:

$$g = \frac{br\ (2003) + br\ (2004E) + br\ (2005E) + br\ (2007E\text{-}2009E\ Avg)}{4}$$

The plowback estimates for all companies in the comparable group can be obtained from The Value Line Investment Survey under the title "percent retained to common equity."

O'Donnell Exhibit No. 3 lists the plowback ratios for each company in the comparable group. This exhibit contains one reference to "NMF" which is the abbreviation for "no meaningful figure". When "NMF" appears, a company's earnings were less than the dividend paid out, which means that the Company did not reinvest or "plowback" any earnings from that year's operations. For purposes of being conservative, I treated the "NMF" entries as a 0 for purposes of my analysis. The plowback method is a very useful tool for comparing the comparable group's growth rates on a recent historical basis as well as a short-term forecasted basis.

The second method I used to estimate the expected growth rate was to analyze the historical 10-year and 5year compound annual rate of change for earnings per share, dividends per share, and book value per share as reported by <u>Value Line</u>. These historical growth rates can be seen in O'Donnell Exhibit No. 1.

The third method I used was the <u>Value Line</u> forecasted compound annual rates of change for earnings per share, dividends per share, and book value per share.

The fourth method I used was the forecasted rate of change for earnings per share that analysts supplied to Charles Schwab & Co. This forecasted rate of change is not a forecast supplied by Charles Schwab & Co. but is, instead, a compilation of forecasts by industry analysts.

The details of my DCF results can be seen in O'Donnell Exhibit No. 1 and a summary of these results can be found in O'Donnell Exhibit No. 2.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS?

As can be seen on O'Donnell Exhibit No. 2, the dividend yield for the three time frames studied ranges from 4.2% to 4.3% for the comparable group. As a result, I believe the proper dividend yield range to use in the DCF model for the comparable group is 4.0% to

4.50%. For SCANA Corp., the dividend yield over the three periods is 4.1% to 4.2%. As a result, I believe that the proper dividend yield to use for SCANA is also 4.0% to 4.5%.

In terms of the proper dividend growth rate to employ in this analysis, I believe that it is appropriate to examine the recent history of earnings and dividend growth to judge the growth in dividends which investors expect in the future. During the past decade the electric utility industry has endured much change. Wholesale market deregulation led to sweeping changes throughout the industry. Many states deregulated retail sales thereby leading to even more changes. Large utilities such as SCANA Corp. responded by becoming active in wholesale power markets and even purchasing other utilities in a consolidation of the industry. Unfortunately, many of the changes in the electric industry began to unravel when California endured an energy crisis in 2001 and Enron fell into bankruptcy soon thereafter.

Given the credit meltdown experience in the utility industry three years ago, energy companies are now placing a premium on their regulated operations that produce a steady stream of cash as opposed to the non-regulated ventures that are not always profitable. Utility investors of little risk tolerance will, generally, seek companies such as SCE&G that have little to no exposure to non-regulated entities that will sometimes, create a severe drag on earnings and threaten dividend payouts.

I believe that investors have recognized that dividend growth in the short-term will be less than short-term earnings growth. Evidence for this belief can be seen in the comparable group's Value Line forecasted earnings per share and dividends per share. As can be shown in O'Donnell Exhibit No. 1, the comparable group's forecasted dividend growth rates are much lower than the forecasted earnings growth rates over the next three to five years. In my opinion, Value Line's forecasted dividend growth rates are accurate for the next three to five years, but are low when the longer term view is considered. I also believe that investors realize that, in the near future, earnings must grow faster than dividends for the comparable group so that companies can decrease their payout ratios and give themselves more financial flexibility as the natural gas and electric industries continue to evolve. On a long-term basis, I believe that investors expect dividends to grow at a pace more in line with that of long-term earnings.

There is no doubt that the recent history of the electric industry was abnormal relative to many years of solid credit ratings as well as steady and expanding growth in dividends. Due to the effects of fundamental changes that have occurred in the electric industry, I believe that it is proper to place more weight on forecasted figures than historical figures in estimating the cost of equity for SCE&G and the comparable group.

For these reasons, I believe that the proper growth rate range for the comparable group of companies to use in the DCF analysis is 4.5% to 5.0%. The 4.5% is appropriate for the lower end of this range since it is approximately equal to the Value Line forecasted earnings per share as well as the average growth rate for the group as found using the plowback method. I believe that 5.0% is appropriate for the high end of the range as it is approximately equal to the group's forecasted earnings per share as compiled by Charles Schwab and Associates.

Combining the dividend yields and growth rates produces a DCF range for the comparable companies of 8.50% to 9.50%.

For SCANA Corp., I believe the proper growth rate to use is in the range of 4.5% to 5.5%. The 4.5% low-end of the range is appropriate as this figure reflects the average forecasted earnings growth rate as reported by Charles Schwab andAssociates. . The high end of the range is appropriate because it reflects the Value Line forecasted earnings per share, dividend per share, and book value per share. The plowback method also produces a 5.5% growth rate for SCANA Corp. as well.

Combining the 4.0% to 4.5% dividend yield range to the 4.5% to 5.5% growth rate range produces a DCF range of 8.5% to 10.0% for SCANA Corp.

B. Return on Equity Recommendation

Q. WHAT IS YOUR ESTIMATE OF THE COST OF EQUITY CAPITAL FOR SCE&G?

A. As I mentioned earlier, the results from my DCF Analysis resulted in an investor return requirement range of 8.50% to 9.50% for the Comparable Group and a range of 8.50% to 10.0% for SCANA Corp. Based upon the results of these two analyses, I recommend that the Commission conclude that the investor return requirement for SCE&G is 10.0%.

Q. HOW DOES THIS 10.0% RATE OF RETURN COMPARE TO THE RETURNS WHICH MONEY MANAGERS NOW EXPECT TO EARN ON LONG-TERM STOCK INVESTMENTS?

A. In my opinion, a 10.0% rate of return on an investment in a electric utility would be deemed fair and appropriate by most money managers. I believe that most professional investors would be very pleased if their managed portfolios produced overall annual returns of 10.0.% in today's investment climate. The stock market had a tremendous bull market run from 1995 through much of 2000, but the most recent four years have been a relatively painful experience for investors.

III. REVIEW OF COMPANY WITNESS MALKIEL'S TESTIMONY

Q. MR. O'DONNELL, HAVE YOU REVIEWED THE TESTIMONY OF DR. BURTON MALKIEL?

A. Yes, I have.

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN HIS RETURN ON EQUITY TESTIMONY AND YOUR RETURN ON EQUITY TESTIMONY?

A. Dr. Malkiel and I both use the DCF method for estimating the return on equity for SCE&G. The end-result from both of our analyses is, however, surprisingly similar. Dr. Malkiel indicates in his testimony that his estimated return on equity using the DCF method was 10.5%, which is very close to my estimated return on equity of 10.0%. The difference in our two testimonies occurs when Dr. Malkiel opines that interest rates will soon rise and that investor return requirements will soon follow. Based on his forecast of interest rate increases, Dr. Malkiel then states that the proper rate of return to employ in this proceeding is in the range of 10.5% and 12.45%.

The burden of proof in this proceeding is upon the Company. In my opinion, neither Dr. Malkiel nor anyone within SCE&G provides any evidence to support a rate of return higher than 10.5%. Wanting a higher rate of return is simply not justification for asking the South Carolina Public Service Commission to approve higher rates for fellow South Carolinians to support a rate of return that cannot be justified.

IV. GRIDSOUTH EXPENSES

Q. DO YOU AGREE WITH THE COMPANY'S REQUEST TO RECOVER APPROXIMATELY $3.5 MILLION PER YEAR ASSOCIATED WITH ITS FAILED INVESTMENT IN THE PROPOSED GRIDSOUTH RTO?

A. No, I do not.

Q. WHY DO YOU OPPOSE SCE&G'S REQUEST TO RECOVER ITS GRIDSOUTH EXPENSES?

A. In my opinion, the GridSouth RTO was essentially a half-hearted effort by SCANA Corp., Duke Energy, and CP&L to comply with a federal mandate for all electric utilities to join regional transmission organizations (RTOs).

As the Commission is aware, the primary purpose in the movement towards RTOs is to enhance the development of competitive wholesale power markets which, in my view, GridSouth simply could not do with only three market participants. In the current wholesale power market, the only realistic power supply options that exist in the Carolinas are Duke, CP&L, and SCE&G. As such, the creation of GridSouth would have done absolutely nothing to enhance the level of competition that already exists in the market.

The fact that GridSouth was eventually terminated is simply more evidence to support the conclusion that the RTO was failed from the start due to its small geographic focus. If, in my opinion, the three Carolina utilities were serious about creating a more competitive wholesale market, a larger RTO involving utilities throughout the southeast or the central Atlantic states would have been created.

Furthermore, from a legal and fundamental fairness standpoint, I am opposed to SCE&G recovering expenses associated with a venture that is not now, nor was it ever, used and useful for the betterment of South Carolina and its citizens.

Q. DO YOU BELIEVE THE COMPANY'S INVOLVEMENT WITH A REGIONAL TRANSMISSION ENTITY IS PERMANENTLY TERMINATED?

A. No, I do not. Both North and South Carolina are beginning to experience transmission problems. Earlier this year, Progress Energy Carolinas (PEC) announced that it had no more import transmission capacity after the year 2010. I am fearful that this admission by Progress Energy Carolinas is just the first of many similar admissions soon-to-come from southeastern utilities.

Not surprisingly, many wholesale customers in the PEC area were quite surprised and unhappy that they could not bring competitively priced power supplies into the PEC service territory after 2010. In my view, the Federal Energy Regulatory Commission (FERC) cannot and will not allow the competitive wholesale market in the Carolinas to wither on a vine and die. I believe that the FERC will step in within the next two years and require some form of a transmission entity involving both North Carolina and South Carolina. When that movement occurs, the costs associated with GridSouth will, once again, become a wholesale rate matter and SCE&G can seek recovery of such costs from the FERC.

Furthermore, on Friday, September 24, 2004, two different sets of utilities, the load serving utilities and the investor-owned utilities, filed plans in North Carolina that would establish what amounts to a RTO-lite scenario in which a single entity would oversee transmission planning for the state. If this situation ultimately develops, I am confident that a similar working group, including South Carolina,would be a distinct possibility, particularly given the fact that both Progress Energy and Duke Power serve both North and South Carolina. As a result, I believe that SCE&G's request to seek recovery of GridSouth expenses is premature at this point in time.

V. REQUESTED CHANGE IN CREDIT STANDARDS

Q. MR. O'DONNELL, WHAT CHANGE DOES SCE&G SEEK IN REGARD TO ITS CREDIT STANDARDS FOR LARGE CONSUMERS?

A. SCE&G is proposing to collect deposits from large consumers that it deems to be a credit risk.

Q. WHAT REASON DOES SCE&G PROVIDE TO SUPPORT THIS CHANGE IN ITS CREDIT STANDARDS?

A. According to the testimony of Mr. Hendrix, SCE&G is seeking this new credit provision because the Company's current terms and conditions do not permit it to seek a deposit from a large customer even if the financial position of the customer is known to be in trouble.

Q. HOW DO MOST UTILITIES RECOVER UNCOLLECTIBLE EXPENSES?

A. Traditional regulatory ratemaking allows the utility to recover uncollectible expenses through a slight increase in current rates.

Q. HAS THE COMPANY PROVIDED ANY EVIDENCE THAT UNCOLLECTIBLE EXPENSES FOR MANUFACTURERS HAS RISEN SINCE THE LAST RATE CASE?

A. No. The Company has provided some figures indicating that "commercial" customer uncollectible expenses have risen over the past two years, but it did not separate commercial customers such as retail stores from industrial customers. As a result, it is impossible to discern from the figures given by the Company whether the increase in uncollectible expenses is from commercial consumers or from industrial consumers.

Q. WHAT IS YOUR RECOMMENDATION IN REGARD TO SCE&G'S REQUEST TO REQUIRE DEPOSITS IN CERTAIN CASES FOR INDUSTRIAL CONSUMERS?

A. To support its request, I believe that SCE&G, at a bare minimum, should have supplied a financial analysis proving that current rate are not set high enough to cover the Company's actual uncollectible expenses during the test year. Unfortunately, the Company did not provide such evidence. As a result, I recommend that the Commission reject SCE&G's request for this credit change in the Company's terms and conditions.

VI. INTERRUPTIBLE RIDERS

Q. WHAT CHANGES IS SCE&G PROPOSING TO ITS INTERRUPTIBLE RIDERS ASSOCIATED WITH RATE SCHEDULES 23 AND 24?

A. In its pre-filed testimony, SCE&G witness Hendrix states the Company is proposing to cap the interruptible rider to Rates 23 and 24 for all current customers at their existing contract levels and close the rider to new accounts. Under the existing tariff, customers that agree to a maximum curtailable period of 150 hours receive a credit of $2.75 per kW and those that agree to be curtailed a maximum of 300 hours per year receive a credit of $4.50 per kW. Mr. Hendrix goes on to state that the Company is also proposing a new interruptible rider that will allow the Company to interrupt for <u>economic and capacity shortage</u> reasons. According to the proposed rider, the interruptible demand credit will be $5.75 per kW. This increase in the credit is contingent upon the customer accepting a maximum annual curtailable period of 450 hours. Customers who chose to accept this new tariff can buy-through any economic interruption at a market price to be provided by the Company.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO CAP THE INTERRUPTIBLE RIDER TO RATES 23 AND 24?

A. No, I do not. The Company has given no evidence to support the changes it is now requesting to the existing riders. An interruptible rider allows a manufacturer to reduce its costs through a credit on its bill by allowing the utility to interrupt the manufacturer's power service at times deemed necessary by the utility. Its actions restrict opportunities by the manufacturing community to cut costs. In today's fiercely competitive economic climate, the utility should not be seeking to limit opportunities of customers to save money in way that also save SCE&G operating costs. In my opinion, the Company's request in this case is directly linked to the completion of the Jasper facility and the fact that the Company now has more than adequate reserve margins for the SCE&G system.

Since the creation of this interruptible rider, large consumers that opted to take service under this rider were willing to take an inferior level of service in return for an opportunity to save money on their power bills. This action on behalf of large consumers provided SCE&G with operational flexibility when the utility was faced with generation capacity shortages. Now, however, SCE&G has an abundance of generation capacity and it wants to limit the money saving options for the large consumers that were instrumental in assisting the utility with capacity shortages prior to Jasper's completion. In my opinion, the Company's request in regard to interruptible riders is very self-serving. I recommend that that this request be rejected by the Commission.

Q. DO YOU OPPOSE THE CREATION OF AN ADDITIONAL RIDER AS PROPOSED BY SCE&G?

A. No, I do not oppose the creation of a new interruptible rider for Schedules 23 and 24. However, I am opposed to allowing SCE&G to curtail for economic reasons. In my opinion, the Company's proposal to allow large consumers to buy-through economic curtailments is a hollow gesture that prevents good production planning on behalf of manufacturers. As the Commission is aware, the wholesale market in the southeastern United States is a work-in-progress that currently has little-to-no transparency. At the present time, there is no single electric index available to consumers in the Southeast where they can check current market prices. If such an index did exist, large consumers could monitor the index on a daily basis in an effort to gauge possible economic curtailments; in turn such large companies can plan production cycles in the event of an actual power interruption.

Furthermore, after an interruption occurs, the lack of a transparent wholesale market does not allow for a proper checking system. Take for example, the situation where SCE&G indicates to a manufacturer that the cost of buying through the interruption will be $80 per MWH. In that case, the manufacturer has no way to know if $80 per MWH is a fair price since there is no index in the southeastern power markets with which to check the price. As a result, the manufacturer that chooses to buy-through an interruption will always be left wondering whether or not they got treated properly in the price offered by SCE&G.

In my opinion, SCE&G should expand and not contract its two existing riders as well as offer the new credit of $5.75 per kW. Ratepayers should not lose money-saving opportunities just because the Company made a large investment in generation equipment.

VII. COST-OF-SERVICE AND RATE DESIGN

Q. MR. O'DONNELL, WHAT IS A COST OF SERVICE STUDY AND WHY ARE THEY RELEVANT TO A RELATIVE RISK ANALYSIS?

A. A cost of service study is the starting point for any relative risk analysis. Before any changes are made to customer class rates, the current cost of serving each customer class and the return which the Company earns on service to that class must be determined. Once this information has been determined, customer class rates can be changed in order to bring the resulting class rates of return in line with the risks of serving each class.

Q. IS COST-OF-SERVICE AN IMPORTANT CONSIDERATION WHEN DETERMINING CUSTOMER CLASS REVENUE REQUIREMENTS?

A. Yes. The information received from performing cost-of-service studies is of great importance. In my opinion, the "bottom line" conclusions from a cost-of-service study should be a primary factor in determining customer class revenue requirements.

Q. HOW IS A COST-OF-SERVICE STUDY PERFORMED?

A. The first step in performing a cost of service study is to determine the appropriate test year for which all revenues, expenses, and utility plant investment are based. In the case of SCE&G, the most recent test year was for the 12 months ending March 31, 2004.

The next step in performing a cost-of-service study is to ascertain the proper level of revenues and expenses to use in this analysis. It is the responsibility of the analyst to ascertain that the revenues and expenses used in the analysis are representative of what the utility can expect on an ongoing basis. Since revenues typically do not vary by a great deal from year-to-year, little adjustments are made in this area. Expenses, on the other hand, can vary considerably so careful consideration must be made with each expense.

Once the revenues and expenses have been adjusted so that they are representative of what the utility reasonably achieved in the test year, the analyst then allocates these revenues and expenses to each of the customer classes. Allocating revenues is a relatively straightforward task since all major utilities, such as SCE&G, normally retain detailed utility revenue accounts for each customer class. Allocating expenses is, however, more difficult because all the expenses are commonly incurred expenses for all customers of the electric distribution system. To allocate these expenses, the analyst must use the allocation factors that are based on factors such as annual usage, demand usage, number of customers, etc. Allocating expenses in this manner is normally called "functionalization" of expenses as the process involves arranging the expenses according to major electric utility functions, such as generation, transmission, and distribution.

The allocation of operating expense items requires careful consideration as to how these expenses and investments are incurred and utilized and how best to spread these costs. It is very important that the analyst allocate the given expense by the way such cost is incurred or in the manner in which these expense items are utilized. For purposes of simplicity and example, consider the situation with postage expenses. The vast majority of postage expenses are incurred in sending monthly bills to consumers. Since each consumer gets a bill in the mail, it makes sense to allocate postage expenses by the number of customers in each rate class. Thus for postage expenses, residential customers would bear the largest portion of this expense since that class has the largest number of individual customers.

Operating expenses can be classified into four major groups: production, transmission, distribution, sales, and administrative and general (A&G) expenses. The method of allocation for each of these four groups will vary as to the way in which these expenses are incurred by the electric utility.

Once the various per customer class revenues and expenses have been determined, an income statement is essentially created for each customer class. From this income statement, income taxes can be calculated and then the net income for each customer class is determined.

The next step in the cost-of-service study is to allocate the utility's net plant investment, which is defined as gross plant less depreciation, in a cost-causation manner similar to how the analyst allocated expenses. As was the case with expenses, net plant investment, otherwise known as the rate base, is allocated in the manner in which the utility incurs the cost. There are three major types of utility plant investment that require allocation: generation, transmission, and distribution. Of these types, generation investment is generally the largest investment. As the largest investment, allocation of generation is critically important in the calculation of the cost of service to each customer class.

The last step in the cost-of-service study is to divide the net income for each customer class by the rate base for each class to derive the rate of return earned on service for each customer class. The resulting percentage (%) rate of return for each customer class provides the analyst with a gauge of the profitability of service to each customer class.

Q. WHAT DO THE RESULTS OF THE COST-OF-SERVICE STUDY TELL THE ANALYST PERFORMING THE COST-OF-SERVICE STUDY?

A. If a customer class rate of return is negative, the utility is earning less than the cost of providing service to that class. In that case, the analyst must consider raising rates to that customer class in order to bring the return on service to that class commensurate with the risk of providing that service. If, on the other hand, the utility is earning a return far greater than the Company's overall rate of return, the analyst should consider reducing rates in order to lower the customer class rate of return.

Q. SHOULD AN ANALYST LOOK AT FACTORS OTHER THAN CUSTOMER CLASS RATES OF RETURN WHEN EXAMINING HOW TO ADJUST RATES?

A. Yes, but rates should be adjusted first and foremost on the cost of providing service to the particular customer class. Failing to consider analytical tools such as cost-of-service models will lead to a highly subjective rate design that will send erroneous price signals to consumers, thereby doing great harm to the underlying economy of the utility's service territory.

Q. PLEASE EXPLAIN HOW NON-COST BASED RATES CAN HARM ECONOMIC CONDITIONS IN A UTILITY SERVICE TERRITORY.

A. Utility rates that are not set to reflect the cost to serve a particular customer or customer class essentially send improper price signals to consumers who then fail to change their usage patterns, thereby raising costs even further for the utility. A good example would be a situation in which an electric utility sets a rate for a highly seasonal customer that does not reflect the customer's peak usage. If rates for a seasonal customer are set below the cost to serve the customer, the customer will have no economic incentive to cut its peak usage. Since peak usage requires the utility to use its most expensive electric generation, more usage from highly variable seasonal customers will drive up the cost of the utility and drain money from consumers who could otherwise spend their hard-earned money in the local economy.

Another example would be if electric rates were established so that one customer class subsidizes another customer class. Such cross-subsidization can have disastrous long-term effects in the local economy. For instance, if industrial consumers are subsidizing other customer classes, they, of necessity, will tire of unnecessarily high electric rates and move jobs out of the utility's service area.

Q. HAVE YOU EXAMINED THE COST-OF-SERVICE STUDY FILED BY SCE&G IN THIS RATE CASE?

A. Yes, I did. I analyzed the summer coincident peak cost-of-service study filed by Mr. John Hendrix as part of his testimony in this proceeding.

Q. WHAT IS A "SUMMER COINCIDENT PEAK" COST-OF-SERVICE STUDY?

A. As stated above, the most critical part of a cost-of-service study for an electric utility is the method in which generation investment is allocated. This one allocation, more so than any other, will have the greatest influence on the resulting customer class rates of return. Since SCE&G is a summer peaking utility, Mr. Hendrix allocated the Company's generation investment to all customer classes by a ratio of each class's summer peak demand relative to the total summer peak demand of the entire SCE&G summer peak demand.

Q. DO YOU AGREE WITH ALLOCATING GENERATION INVESTMENT BY THE SUMMER COINCIDENT PEAK?

A. Yes, since SCE&G builds generating plant to meet the peak demand on its system, which occurs in the summer season, it make sense to allocate generation investment by the summer coincident peak ratio.

Q. CAN YOU PROVIDE ANY EVIDENCE TO SUPPORT YOUR STATEMENT THAT SCE&G IS A SUMMER PEAKING UTILITY?

A. Yes. Below is a table of the summer and winter peaks forecasted by SCE&G over the next fifteen years. As can be seen in this exhibit, SCE&G's summer peak is expected to exceed its winter peak in each of the next fifteen years.

Table 1: Peak Loads of SCE&G

Year	Summer Peak (MW)	Winter Peak (MW)
2004	4,506	4,146
2005	4,593	4,225
2006	4,699	4,332
2007	4,811	4,442
2008	4,925	4,553
2009	5,039	4,670
2010	5,166	4,805
2011	5,279	4,919
2012	5,408	5,051
2013	5,533	5,181
2014	5,662	5,313
2015	5,775	5,426

2016	5,888	5,544
2017	6,017	5,682
2018	6,132	5,809

Source of data is SCE&G 2003 Integrated Resource Plan

As a result, SCE&G must use its summer peak as its benchmark in planning to meet its generation needs in the future.

Q. DOES THE SUMMER COINCIDENT PEAK METHOD REFLECT THE MANNER IN WHICH SCE&G'S CUSTOMERS USE ELECTRICITY?

A. Yes. SCE&G has three major customer classes: residential, commercial, and industrial. Of these three classes, the residential class is the most temperature-sensitive and time-sensitive class. Put simply, when the temperature rises outside the home, residential consumers respond by running their air conditioners more frequently. The time at which residential consumers use the most electricity is, typically, the late afternoon hours of a hot summer day when workers come home from work. To accommodate the need for electricity, SCE&G must ramp up its more expensive generating plants to meet this summer peak demand.

Industrial consumers, on the other hand, keep their energy consumption relatively level as these customers are much less sensitive to temperature fluctuations than are residential consumers. Furthermore, it is often very costly for a large manufacturer to ramp up and down its manufacturing operations due to the stresses that such variations place on manufacturing equipment.

Q. IS THERE AN ANALYTICAL WAY TO COMPARE HOW EACH CUSTOMER USES ELECTRICITY?

A. Yes. One way is to compare a customer's energy use, measured in kWh or MWH, relative to the peak demand that the customer places on the entire electric system. This calculation is referred to as the load factor and is calculated by simply dividing energy use for a given period by the peak demand of the same customer for the same period. A customer with a high load factor is one whose load is relatively constant throughout the time period. A high load factor customer is the most desired customer on the utility system as the power that serves these customers is primarily derived from baseload plants such as its coal and nuclear plants that have relatively low fuel costs.

Low load factor customers, on the other hand, are customers whose usage varies widely and is, at least here in the Southeast, highly dependent on summertime heat. The high variability of low load factor customers also requires the utility to operate peaking units such as natural gas fired units whose fuel costs are more expensive than baseload plants. These peaking plants are, in general, not operated very frequently throughout the year due to their high operating costs.

Below is a table showing the load factors on the SCE&G system for the test year ending March 31, 2004.

Table 2: SCE&G Customer Load Factors

Customer Class	Sales (kWh)	Demand (kW)	Load Factor (%)
Residential	7,050,682,277	1,772,245	45.4%
Commercial	5,534,547,887	1,140,602	55.4%
Industrial	6,115,694,754	1,108,793	63.0%
Total Utility	20,395,400,343	4,325,001	53.8%

The low load factor of the residential class reflects the highly variable energy usage of residential customers. The industrial class, in contrast, has a high load factor, thereby reflecting the steady energy demand placed by industrial consumers on the SCE&G system. Based on this table, it is clear that the residential consumers are the driving force behind the system planning needs of SCE&G. This difference in load factors is, in my opinion, more justification to support the use of a summer coincident peak allocation for generation investment of SCE&G, as it is the highly variable residential class that is driving the peak demands of the utility.

Q. ARE THERE ALTERNATIVE COST-OF-SERVICE METHODOLOGIES USED BY ANALYSTS?

A. Yes, there are two other cost-of-service methodologies, the peak and average method and the 12-month coincident peak (CP) method, that are sometimes advanced by analysis in regulatory rate cases.

Q. PLEASE EXPLAIN BOTH THE PEAK AND AVERAGE COST-OF-SERVICE METHOD AS WELL AS THE 12-MONTH CP COST-OF-SERVICE METHOD.

A. The peak and average cost-of-service method allocates generation equipment based on a split, typically on a 50/50 basis, between each customer class's contribution to the system-wide peak demand as well as each customer class's share of energy used by the total system. By allocating generation equipment in this manner, the analyst is essentially saying that the choice of generation plant constructed on the utility's system is dependent on the amount of energy (e.g. kWh) used as well as the total demand (kW) placed on the system. Advocates of this method claim that the peak and average cost-of-service study is fair because it gives considerable weight to energy use characteristics of individual customer classes.

The 12-month CP cost-of-service methodology allocates generation plant based on each customer class's contribution to each monthly peak demand on the total utility system. Under this methodology, the analyst basically assumes that the utility must plan to meet the peak demands of the system on each and every month. As a result, the 12-month CP methodology gives equal weight to peak usage that occurs in October, which is a shoulder month in which little electricity is used as a whole, as well as in August, which is when most annual peak demands occur for southeastern states. Advocates of this methodology claim that it is fair because it simulates the actual operation of the electric system on a monthly basis and more closely follows fuel consumption, which obviously varies by monthly peak usage.

Q. IN YOUR OPINION, WHAT ARE THE PROBLEMS WITH USING THE PEAK AND AVERAGE COST OF SERVICE STUDY AND THE 12-MONTH PEAK COST OF SERVICE STUDY.

A. Both of these methodologies suffer from the same flaw; that is that neither method properly reflects the manner in which SCE&G operates its electric system. It is clear from reviewing load forecast material from SCE&G that the utility plans to meet one annual peak demand and that demand occurs in the summertime. Adoption of either one of these cost-of-service methodologies would send the wrong economic signal to customers of the SCE&G system, thereby resulting in misuse of the Company's electric system.

The peak and average cost of service methodology incorrectly assumes that a utility constructs its system based on the use of energy by customers as well as the peak demand use of customers. Such an assumption is incorrect. Energy use is a product of time and the customer requirements placed on the utility system. Demand, on the other hand, represents the peak load that the system planner must meet each and every year. The focus of the utility planner must be on meeting the annual peak demand, which in the case of SCE&G, is the summer peak demand.

Similarly, the 12-month peak cost-of-service study is flawed because it assumes that the utility planner gives equal weight to the October monthly peak load, for example, and to the August peak load. Such assumptions are simply false and illogical. Adoption of a 12-month peak cost-of-service study would result in erroneous economic signals being sent to consumers who may then change usage patterns, thereby resulting in an inefficient use of the SCE&G electric system.

According to testimony from Mr. Hendrix, the South Carolina Public Service Commission has been using the summer peak CP cost-of-service methodology for over 25 years. In my opinion, the Commission has been using the proper cost-of-service methodology during this time frame as it sends the proper economic signals to consumers of SCE&G. Adoption of a cost-of-service study different from the summer peak methodology would not be in the best interest of SCE&G or its customers.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S COST-OF-SERVICE STUDY?

A. In Table 3 below are the results of the proforma Company cost-of-service study as well as the proforma cost-of-service study with proposed rates.

Table 3 : Result of SCE&G Cost-of Service Studies

Study	Total Co.	Res.	Small GS	Medium GS	Large GS	St. Light.	Retail
Pro Forma w/ existing rates	7.39%	6.64%	8.68%	7.95%	8.66%	8.18%	7.61%
Pro Forma w/ prop. rates	8.89%	8.87%	9.49%	9.34%	9.47%	9.58%	9.18%

Q. HOW DOES SCE&G PROPOSE TO CHANGE RATES IN THIS CASE?

A. SCE&G is seeking to raise rates to all customer classes it serves. In Table 4 below is a summary of the customer class rate changes proposed by the Company in this case.

Table 4: Company Proposed Rate Changes

	Total Co.	Res.	Small GS	Medium GS	Large GS	St. Light.
Rate Change	5.66%	8.81%	3.31%	5.01%	2.01%	6.25%

Q. **DO YOU AGREE WITH THE COMPANY'S RATE CHANGE PROPOSALS IN THIS CASE? IF NOT, WHY NOT?**

A. No, I do not. As I stated earlier, I believe that the Company does not need the full rate increase that it has requested. As a result, all requested customer class rate increases should be reduced in line with my recommendation in this case.

Q. IF THE COMMISSION DISAGREES WITH YOUR REVENUE RECOMMENDATIONS IN THIS CASE AND GRANTS THE UTILITY SOME

OF ITS REQUESTED RATE INCREASE, HOW DO YOU BELIEVE RATES SHOULD BE DESIGNED?

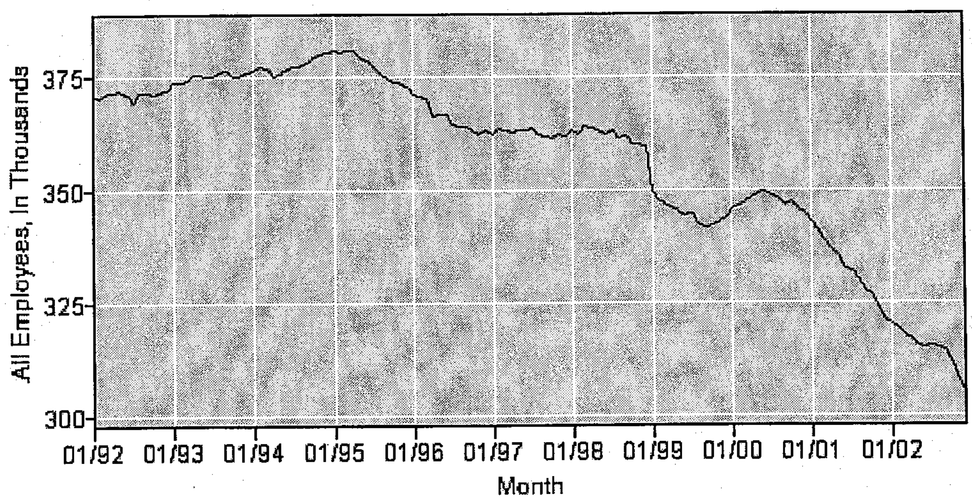
A. If the Commission decides to grant a rate increase to SCE&G, I believe that the majority, if not the entire rate increase, should be placed on the residential customer class.

As can be seen in Table 3 above, the residential class is currently earning a return of 6.64% as compared to the large general service class which primarily consists of the industrial customers and is providing the Company a return of 8.66%. Based on these figures, it is clear that SCE&G's industrial consumers are subsidizing the Company's residential consumers. If this subsidization is allowed to continue, the South Carolina economy will suffer, tax revenues from manufacturers will fall, and more South Carolina manufacturing jobs could be lost. Based on this information, I believe that residential consumers should absorb the revenue increase sought by SCE&G in this case.

Q. WHAT IMPACT DO SOUTH CAROLINA MANUFACTURERS HAVE ON THE STATE OF SOUTH CAROLINA?

A. The primary impact of manufacturers in South Carolina is through employment. As of July, 2004, South Carolina manufacturers employed 270,600 individuals. While this figure may sound impressive, it is important to note that manufacturing employment in South Carolina is down substantially from its high of approximately 380,000 in 1995. On the next page is a graph of South Carolina manufacturing employment over the past 11 years.

South Carolina Manufacturing Employment



Source of graph: U.S. Dept. of Labor, Bureau of Labor Statistics
http://data.bls.gov/servlet/SurveyOutputServlet

As the Commission pointed out in its 2002 Piedmont Final Order, South Carolina manufacturers also provide substantial property tax payments to support local governments. Furthermore, for the state as a whole, South Carolina manufacturers provide much-needed revenue from corporate income taxes. In 2005, for example, corporate tax revenues in South Carolina are estimated to be over $120 million.

There are also numerous ancillary benefits of manufacturing in South Carolina. The ripple effect of a company locating in the state can be seen well beyond the immediate gates of the manufacturer. Soon after a plant announcement is made, contractors, subcontractors, and suppliers typically all swing into action to support the manufacturing facility. Service companies also benefit by meeting the needs of the manufacturing facility. All these supplier and service entities provide tax revenues to local communities as well as the State of South Carolina. Without such tax revenues, South Carolina could not provide many of the services that its citizens now enjoy.

Q. HAS THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION RECOGNIZED THE NEED TO REDUCE OR ELIMINATE CROSS-SUBSIDIZATION AMONGST UTILITY RATE CLASSES?

A. Yes, in Docket No. 2002-63-G, which was the final order in Piedmont Natural Gas Company's last rate case in 2002, the Commission stated:

1. The records show that industrial customers were subsidizing residential and commercial customers. Reduction or elimination to this subsidization was viewed favorably.
2. Appropriate industrial rate designs could help the state of South Carolina retain existing industry and perhaps attract new industry. The Commission found that was particularly important given the significant loss of manufacturing jobs in the state of South Carolina in recent years. The Commission also observed that the loss in manufacturing jobs had a profound affect on personal income, personal income tax revenues, and unemployment payments and other government-related costs.
3. The Commission also observed the appropriate rate design principles help respond to the price sensitive industrial market and better allow natural gas companies to compete with alternative fuels for these price sensitive companies.

Based on these statements, the South Carolina Public Service Commission is painfully aware of the tremendous loss of manufacturing jobs within the state and is ready to create public policy to eliminate these cross-subsidizations. In my opinion, the gap between the residential and industrial class rates of return needs to be narrowed at a minimum to that which SCE&G is proposing in this case.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

SCANA Corp.

Docket No. 2004-178-E

Company	DCF Results													
	26 Wk. Avg. Dividend Yield	13 Wk. Avg Dividend Yield	4 Wk. Avg. Dividend Yield	Value Line									Plowback Growth Rate	Schwab Forecasted EPS
				10 Year			5 Year			Forecasted				
				EPS	DPS	BPS	EPS	DPS	BPS	EPS	DPS	BPS		
Alliant Energy	3.9%	3.9%	3.9%	-2.5%	-1.0%	1.5%	-1.0%	-3.5%	1.0%	3.0%	-6.0%	3.5%	3.5%	4.3%
Ameren	5.7%	5.6%	5.5%	1.0%	1.0%	2.0%	2.5%	---	2.5%	nil	nil	4.5%	1.6%	3.3%
Avista Corp.	3.0%	2.9%	2.9%	-3.5%	-9.0%	3.0%	-9.0%	-16.5%	4.0%	7.5%	6.5%	4.5%	3.9%	4.5%
CH Energy Group	4.7%	4.8%	4.7%	0.5%	1.0%	2.5%	-2.0%	---	2.0%	0.5%	nil	1.0%	1.8%	N/A
Cinergy	4.8%	4.6%	4.7%	1.5%	1.0%	0.5%	3.0%	0.5%	4.0%	3.5%	2.0%	5.5%	3.4%	4.0%
Constellation Energy	3.0%	3.0%	3.0%	4.0%	-5.5%	3.0%	4.5%	-12.5%	4.0%	11.0%	12.5%	8.0%	7.8%	7.3%
Dominion Resources	4.2%	4.2%	4.1%	3.0%	0.5%	2.5%	9.5%	---	3.5%	7.5%	2.0%	6.0%	5.9%	5.9%
DTE Energy	5.1%	5.1%	5.0%	-2.0%	0.5%	3.5%	---	---	3.5%	4.0%	0.5%	5.0%	3.3%	4.8%
Duke Energy	5.2%	5.1%	4.9%	2.5%	2.5%	4.5%	1.0%	0.5%	7.5%	-2.5%	-5.0%	2.5%	1.3%	4.3%
Energy East Corp.	4.4%	4.4%	4.6%	3.5%	-1.0%	4.0%	4.0%	6.0%	4.5%	3.5%	5.0%	4.0%	3.2%	4.4%
Exelon	3.4%	3.4%	3.5%	---	---	---	---	---	---	6.0%	11.5%	9.0%	10.1%	5.3%
MGE Energy	4.3%	4.3%	4.3%	1.0%	1.0%	1.5%	7.0%	1.0%	3.5%	6.0%	0.5%	7.0%	3.4%	N/A
NiSource	4.4%	4.4%	4.4%	4.0%	6.0%	8.0%	0.5%	4.5%	11.5%	4.5%	-0.5%	3.5%	3.8%	4.9%
Northeast Utilities	3.4%	3.4%	3.4%	-4.5%	-11.5%	0.5%	---	-1.0%	0.5%	10.0%	9.5%	4.5%	4.3%	4.5%
NSTAR	4.7%	4.7%	4.6%	5.0%	2.5%	3.0%	4.5%	2.5%	2.5%	3.0%	2.5%	4.0%	4.8%	4.3%
OGE Energy	5.3%	5.3%	5.2%	0.5%	---	1.5%	-3.5%	---	1.5%	5.0%	1.0%	3.5%	2.9%	3.7%
PNM Resources	3.1%	3.0%	3.0%	12.5%	---	5.5%	4.5%	8.0%	6.0%	-1.0%	4.5%	3.5%	3.6%	5.0%
PPL Corp.	3.7%	3.6%	3.7%	5.5%	-1.5%	-0.5%	10.5%	-3.0%	-0.5%	4.5%	7.0%	13.5%	9.3%	5.1%
P.S. Enterprise Group	5.3%	5.5%	5.4%	4.5%	---	---	8.0%	---	-1.5%	-1.0%	1.5%	7.0%	4.5%	3.3%
Puget Energy, Inc.	4.6%	4.5%	4.4%	-5.5%	-3.0%	-1.0%	-6.0%	-6.0%	-1.0%	6.0%	-3.0%	3.5%	2.5%	5.3%
Sempra Energy	2.9%	2.8%	2.7%	4.5%	-3.5%	1.5%	9.0%	-8.5%	2.0%	5.0%	nil	13.0%	9.8%	6.8%
TECO	5.9%	5.9%	5.8%	0.5%	3.0%	4.5%	-3.0%	1.0%	2.5%	6.5%	-3.5%	3.0%	2.6%	N/A
Vectren Corp.	4.8%	4.8%	4.8%	---	---	---	---	---	---	5.0%	3.0%	3.5%	3.4%	7.0%
Wisconsin Energy	2.6%	2.4%	2.7%	2.0%	-4.5%	2.0%	9.0%	-12.0%	2.0%	6.0%	4.0%	7.5%	6.2%	6.0%
WPS Resources	4.8%	4.7%	4.8%	1.5%	2.0%	3.5%	7.0%	2.0%	5.0%	3.5%	2.0%	4.5%	2.9%	4.3%
Average	4.3%	4.3%	4.2%	1.7%	-1.0%	2.6%	2.9%	-2.2%	3.1%	4.3%	2.3%	5.4%	4.4%	4.9%
SCANA Corp.	4.2%	4.1%	4.1%	3.5%	-0.5%	4.5%	3.0%	-3.0%	4.5%	5.5%	5.5%	5.5%	5.5%	4.5%

Source: The Value Line Investment Survey: Sept. 3, 2004; Oct. 1, 2004; and Aug. 13, 2004.

South Carolina Energy Users Committee

O'Donnell Exhibit No. 1

SCANA Corp.

Docket No. 2004-178-E

Summary of DCF Results							
Company	26 Wk. Avg. Dividend Yield	13 Wk. Avg. Dividend Yield	4 Wk. Avg. Dividend Yield	Average Growth Rate	Historical Growth Rate	Plowback Growth Rate	Fore. Growth Rate
Alliant Energy	3.9%	3.9%	3.9%	0.3%	-0.9%	3.5%	1.2%
Ameren	5.7%	5.6%	5.5%	2.3%	1.8%	1.6%	2.0%
Avista Corp.	3.0%	2.9%	2.9%	-0.4%	-5.2%	3.9%	5.8%
CH Energy Group	4.7%	4.8%	4.7%	0.7%	0.8%	1.8%	0.4%
Cinergy	4.8%	4.6%	4.7%	2.6%	1.8%	3.4%	3.8%
Constellation Energy Gro	3.0%	3.0%	3.0%	4.0%	-0.4%	7.8%	9.7%
Dominion Resources	4.2%	4.2%	4.1%	4.6%	3.8%	5.9%	5.4%
DTE Energy	5.1%	5.1%	5.0%	2.6%	1.4%	3.3%	3.6%
Duke Energy	5.2%	5.1%	4.9%	1.7%	3.1%	1.3%	-0.2%
Energy East Corp.	4.4%	4.4%	4.6%	3.7%	3.5%	3.2%	4.2%
Exelon	3.4%	3.4%	3.5%	8.4%	N/A	10.1%	8.0%
MGE Energy	4.3%	4.3%	4.3%	3.2%	2.5%	3.4%	4.5%
NiSource	4.4%	4.4%	4.4%	4.6%	5.8%	3.8%	3.1%
Northeast Utilities	3.4%	3.4%	3.4%	1.7%	-3.2%	4.3%	7.1%
NSTAR	4.7%	4.7%	4.6%	3.5%	3.3%	4.8%	3.5%
OGE Energy	5.3%	5.3%	5.2%	1.8%	0.0%	2.9%	3.3%
PNM Resources	3.1%	3.0%	3.0%	5.2%	7.3%	3.6%	3.0%
PPL Corp.	3.7%	3.6%	3.7%	4.5%	1.8%	9.3%	7.5%
P.S. Enterprise Group	5.3%	5.5%	5.4%	3.3%	3.7%	4.5%	2.7%
Puget Energy, Inc.	4.6%	4.5%	4.4%	-0.7%	-3.8%	2.5%	3.0%
Sempra Energy	2.9%	2.8%	2.7%	4.0%	0.8%	9.8%	6.2%
TECO	5.9%	5.9%	5.8%	1.7%	1.4%	2.6%	1.5%
Vectren Corp.	4.8%	4.8%	4.8%	4.4%	N/A	3.4%	4.6%
Wisconsin Energy	2.6%	2.4%	2.7%	2.6%	-0.3%	6.2%	5.9%
WPS Resources	4.8%	4.7%	4.8%	3.5%	3.5%	2.9%	3.6%
Average	4.3%	4.3%	4.2%	2.9%	1.6%	4.4%	4.1%
SCANA Corp.	4.2%	4.1%	4.1%	3.5%	2.0%	5.5%	5.3%

Source: The Value Line Investment Survey: Sept. 3, 2004; Oct. 1, 2004; and Aug. 13, 2004.

SCANA Corp.
Docket No. 2004-178-E

Company	Plowback Growth Rate				
	2003	2004E	2005E	2007E-2009E	Avg.
Alliant Energy	2.5%	4.0%	4.0%	3.5%	3.5%
Ameren	2.2%	1.0%	1.5%	1.5%	1.6%
Avista Corp.	3.4%	3.0%	4.5%	4.5%	3.9%
CH Energy Group	2.0%	2.0%	1.0%	2.0%	1.8%
Cinergy	3.0%	3.5%	3.5%	3.5%	3.4%
Constellation Energy Group	7.0%	7.5%	8.0%	8.5%	7.8%
Dominion Resources	4.0%	6.0%	6.5%	7.0%	5.9%
DTE Energy	2.5%	3.0%	3.5%	4.0%	3.3%
Duke Energy	NMF	1.0%	0.5%	3.5%	1.3%
Energy East Corp.	3.1%	3.0%	3.0%	3.5%	3.2%
Exelon	11.5%	11.5%	10.0%	7.5%	10.1%
MGE Energy	2.5%	3.5%	3.5%	4.0%	3.4%
NiSource	3.0%	3.5%	4.0%	4.5%	3.8%
Northeast Utilities	3.7%	4.0%	4.0%	5.5%	4.3%
NSTAR	5.2%	5.0%	4.5%	4.5%	4.8%
OGE Energy	3.6%	2.0%	2.5%	3.5%	2.9%
PNM Resources	3.0%	4.0%	4.0%	3.5%	3.6%
PPL Corp.	11.7%	8.5%	9.0%	8.0%	9.3%
P.S. Enterprise Group	6.5%	4.0%	4.0%	3.5%	4.5%
Puget Energy, Inc.	2.1%	1.5%	3.0%	3.5%	2.5%
Sempra Energy	11.3%	10.0%	9.0%	9.0%	9.8%
TECO	nmf	nmf	3.5%	7.0%	2.6%
Vectren Corp.	3.0%	2.5%	3.5%	4.5%	3.4%
Wisconsin Energy	7.4%	5.0%	6.0%	6.5%	6.2%
WPS Resources	2.0%	3.0%	3.5%	3.0%	2.9%
				Avg.	4.4%
SCANA Corp.	5.5%	5.5%	6.0%	5.0%	5.5%

Source: The Value Line Investment Survey: Sept. 3, 2004; Oct. 1, 2004; and Aug. 13, 2004.